Submission: Clean Electricity Regulations Canadian Gazette, Part 1

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Summary of Recommendations

The Clean Electricity Regulations (CER) are the cornerstone of a comprehensive package of policies needed to achieve the Government of Canada's target of a net-zero electricity grid in 2035. The CER is complemented by a number of existing policy measures, including carbon pricing and federal funding of clean electricity through the investment tax credits (ITCs) announced in Budget 2023, as well as additional measures that will be needed – in particular, a policy that would ensure any residual emissions are offset with negative emissions.

We accept that some amount of residual emissions will remain under the CER, in the interest of avoiding the ratepayer impacts and/or system reliability challenges that would result from a move to full-on net zero under the regulation by 2035. In fact, our submission in two places recommends increasing flexibility – and thereby residual emissions – in the interest of supporting achievability and protecting reliability. It is our view that these residual emissions are best addressed outside of the scope of the regulation, in particular using strengthened carbon pricing and a policy that procures offsetting negative emissions on behalf of the sector.

The most cost-effective pathway to achieving the government's 2035 target will come from ensuring each of these measures is properly designed to address discrete challenges, and to complement the limitations of other measures. We commend the government for their ambitious and largely effective design of the CER, as laid out in *Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations*.[1] However, for the CER to put the sector on a cost-effective decarbonization trajectory that will ensure reliability and protect affordability, we have the following recommendations:

[1] Environment and Climate Change Canada. *Canada Gazette, Part I, Volume 157, Number 33: Clean Electricity Regulations.* https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html (2023).

Regulatory Component	Recommendation
Performance standard	Recommendation: Increase the performance standard to no more than 60 tonnes of CO2 per GWh.
	Recommendation: Establish a compliance flexibility mechanism that allows units that are within a specified margin of the performance standard to achieve the remaining reductions through the purchase of offsets.
End-of-prescribed-life (EOPL)	Recommendation: Maintain current "Prescribed Life" provision of 20 years for facilities commissioned before January 1st, 2025.
Peaker provisions	Recommendation: Adjust flexibilities for units operating as peakers to operate at no more than a 15% capacity factor.
Treatment of facilities commissioned post-2025	Recommendation: Immediately apply an interim performance standard to "new" units that tightens to the level of the full standard by 2035.

In addition to the CER, there are a number of complementary policy changes that will be needed to deliver on the goal of a net-zero electricity grid in 2035. These include:

1. Providing a clear signal of the Government of Canada's intention to apply a full carbon price to electricity sector emissions (with associated revenues returned to a province's ratepayers) and provide a timeline for when these reforms will take effect. Applying full carbon pricing in the electricity sector will more strongly incentivize the deployment of non-emitting electricity generation technologies and deter the use of emitting ones. The current application of output-based pricing in the electricity sector is undermining the effectiveness of the carbon price.

2. Establishing a new Government of Canada policy aimed at ensuring that post-2035 emissions in the electricity sector are net zero. Achieving net zero and even negative emissions in the sector will require the deployment of technologies that remove carbon dioxide from the atmosphere. The federal government should procure a sufficient quantity of negative emissions from both direct air capture with carbon capture and storage (DAC-CCS) and bioenergy with carbon capture and storage (BECCS) to offset residual emissions from the sector 2035 on. This cost should not fall on the electricity sector, provinces, nor their ratepayers.

3. Targeting new Government of Canada investments and programming supports toward DERs, demand-side management (DSM) and energy efficiency. Current supports such as the federal government's Investment Tax Credits (ITCs)are focused on supply-side measures, creating a distortion that risks leaving cost-effective demand-side interventions unrealized. Additional support for these measures can help ensure grids have both the flexibility and reliability they need as Canada decarbonizes, as well as support affordability for households.

Detailed Recommendations

Establishing an effective framework for the Clean Electricity Regulations

For the past several years, the Government of Canada has been putting in place a suite of clean electricity policies and programs, each of which plays a different, yet complementary, role in achieving the stated target of a net zero electricity grid by 2035.

With the release of the Canadian Gazette Part 1 of the Clean Electricity Regulations (CER), the government has provided the details for one of the keystone policies that will be required.[2]

Overall, we strongly agree with the development of a policy framework for the CER that does not deliver net zero emissions from the electricity sector on its own. Having a non-zero emission standard and built-in flexibilities that allow for continued emission in specific situations where emergencies or grid reliability necessitate are important features of the CER. Trying to solve every challenge we face, or saddling the CER alone with the full responsibility to deliver a net-zero grid, would be a mistake.

For the CER to be most effective, it should be designed to address two specific gaps in the current electricity policy framework:

(1) Create a planned trajectory for the decarbonization of the electricity sector. This is essential for achieving Canada's 2050 net zero target and de-risking the rapid investment into non-emitting generation. It will provide the necessary policy certainty for investors, utilities, and system operators around the timing of key capital investments. While the existing carbon price helps provide a market signal for making investments in non-emitting generation, it is not designed optimally; and even under a more optimal design, it is unlikely to drive emissions down in line with the governments' 2035 target on its own.[3]

[2] Ibid.
[3] As outlined in more detail below, we also recommend changes to the carbon price that would allow it to serve as a more effective complement to the CER.

(2) Discourage any further investment in new, unabated fossil gas generating facilities, reducing the risk of further gas lock-in and/or the creation of potentially stranded assets.[4] A number of Canadian provinces have proposed new gas plants to meet growing electricity needs. These facilities represent significant new sources of emissions and risk displacing needed investments in non-emitting electricity generation.

While the proposed regulations include many design elements that will help to achieve these goals in a way that appropriately balances decarbonization with the imperative to maintain system reliability, Clean Energy Canada and the Canadian Climate Institute recommend some changes that will help improve this balance. Our recommendations largely fall within three categories: a) ensuring the performance standard reflects an achievable target for average fossil gas units; b) providing more flexibility for fossil gas operations for the purposes of grid reliability; and c) ensuring the CER will provide a sufficient deterrent to prevent further investment in new unabated fossil gas.

In addition to our proposed changes to the draft regulations, we also recommend three complementary policy actions outside of the CER that will help produce a larger coherent and cost-effective clean electricity policy package.

Specific recommended changes to the CER

Performance standard

Recommendation: Increase the performance standard to no more than 60 tonnes of CO_2 per GWh.

By setting a near-zero performance standard for electricity emissions, the CER will reduce electricity sector emissions while remaining technology neutral.

However, given the binary nature of the CER, where a unit either achieves the standard or is required to shut down, it is also important that the performance standard is set at a level that is ambitious but achievable for an average high-efficiency combined cycle fossil gas unit (either with a high rate of capture via carbon capture technology or via high levels of low-carbon hydrogen or bioenergy blending).

We commend the federal government's emissions reduction ambition in proposing a standard of 30 tonnes of CO_2 per GWh. But we're concerned that that physical standard will be too high for many fossil gas generators—including the highly-efficient ones—to achieve without further compliance flexibilities.

[4] Fossil gas has the same meaning as "natural gas" as defined in the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. The use of "fossil gas" in this submission is to differentiate it from biogas and other forms of renewable/cleaner gas.

In our discussion below, we primarily focus on the performance standard's implications for carbon capture given its importance as a pathway for provinces that have more fossil fuel generation assets. However, the standard also has implications for other pathways like hydrogen blending. The use of hydrogen as a pathway warrants careful consideration in the design of the performance standard, as provinces with a geology that is less supportive of carbon capture (such as Ontario) will rely more heavily on hydrogen or bioenergy to achieve the performance standard.

We can consider the implications for gas plants of the currently proposed performance standard by referencing the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity,* established by the Government of Canada in 2018, which require most fossil gas units to achieve an emissions standard of 420 tonnes of CO_2 per GWh by 2021.[5] In Canada's 5th Biennial Report United Nations Framework Convention on Climate Change (UNFCCC), the Government of Canada noted that this represented an "attainable performance standard on new fossil gas generators."[6] Under the currently proposed CER requirements, a 30 tonne of CO_2 per GWh standard would require a capture rate of roughly 95% through carbon capture.

It is unclear whether this rate of capture is achievable within the timelines of the CER. One prominent study has shown capture rates greater than 90% to be both technically and economically feasible (although not without cost).[7] On the other hand, CCS has so far failed to cost-effectively achieve this rate of capture in practice. And given the binary nature of the CER, the risk of companies forgoing the investment altogether cannot be ignored.

Therefore, we propose adopting a CER performance standard of not more than 60 tonnes of CO_2 per GWh, which would correspond with a 90% capture rate for a fossil gas plant performing at this "attainable" standard (i.e. of 420 tonnes of CO_2 per GWh), striking a better balance between a performance standard that is ambitious yet achievable. This calculation includes accounting for the "parasitic load" associated with CCS operation, which according to the Global CCS Institute can fall between 20-30%. Our calculation assumes a parasitic load of 25%.[8]

<u>Recommendation: Establish a compliance flexibility mechanism that allows units that are within a specified margin of the performance standard to achieve the remaining reductions through the purchase of offsets.</u>

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[5] Government of Canada. *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity.* https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-261/page-1.html#h-857535 (2018).
[6] Government of Canada. *Canada's 8th National Communication and 5th Biennial Report.* https://unfccc.int/sites/default/files/resource/Canada%20NC8%20BR5%20EN.pdf (2022).
[7] Brandl, P., Bui, M., Hallett, J. and Mac Dowell, N. Beyond 90% capture: Possible, but at what cost?. *International Journal of Greenhouse Gas Control* ***73***, 103239 (2021).
[8] Global CCS Institute. CO_2 Capture Technologies: Post Combustion Capture (PCC). https://www.globalccsinstitute.com/archive/hub/publications/29721/co2-capture-technologies-pcc.pdf (2012).

The CER is intended to incentivize the deployment of non-emitting technologies for energy generation, including abatement technologies like carbon capture. As currently drafted, however, the proposed regulations could have the opposite effect.

For instance, under the current proposed regulations, a unit operator acting in good faith could make the significant investment to equip their units with carbon capture technology, only to find it falls short of the required performance standard by less than 1% (a risk which would be mitigated, but not eliminated, by changing the level of the performance standard as we discuss above). As currently drafted, the regulations would require the unit to eventually cease operation —removing the possibility of recovering the costs of the carbon capture investment. Such a risk may lead operators to forgo investment in carbon capture altogether.

To address this concern, the government should establish a "soft-landing" pathway, where units are required to achieve the vast majority of the performance standard through direct emission reductions but may use offsets — such as negative emissions offsets — for the remaining reductions required.

If offsets are used as the compliance mechanism, the government must ensure that offsets represent real, independently verified, quantifiable, permanent, and additional negative emissions.

End-of-prescribed-life (EOPL)

Recommendation: Maintain current "Prescribed Life" provision of 20 years for facilities commissioned before January 1st, 2025

As currently drafted, the CER provides up to a 20-year grace period before the regulations take effect on fossil gas facilities that are commissioned before January 1st, 2025. This is an important flexibility mechanism that helps ensure system operators can reasonably manage the retirement of emitting units without leading to major price shocks or grid reliability issues. As units reach their EOPL at different times, it allows for staggered decision making as to whether a system operator will seek to replace the services it provides through non-emitting technologies, or equip the unit with carbon capture technology. This allows for predictable cost and reliability management and the planned procurement of alternatives where necessary.

Having a 20-year EOPL also helps support the profitability of private investments that have been made under previous rules. Combined-cycle fossil gas facilities have been shown to have a payback period of between 9-17 years, considerably less than the 20-year EOPL considered by the CER.[9]

[9] Carvalho, R., Hittinger, E. & Williams, E. Payback of natural gas turbines: A retrospective analysis with implications for decarbonizing grids. *Utilities Policy* **73**, 101307 (2021).

Increasing the "end-of-project-life" (EOPL) provisions beyond the 20 years should not be considered. Adding additional time to the EOPL provisions will simply delay the needed investments into non-emitting technologies and lead to higher emissions. As noted in the Canadian Energy Regulator's *Canada's Energy Future 2023*, a cost-effective pathway to net zero requires unabated fossil fuel generation to fall to zero as quickly as possible, only remaining available for emergency scenarios.[10]

Where protecting reliability is a concern, the government should consider changes to the peaker provision (as detailed in the following section), rather than extensions to the EOPL.

Peaker provision

Recommendation: Adjust flexibilities for units operating as peakers to operate at no more than a 15% capacity factor

The Clean Electricity Regulations currently propose allowing fossil gas units to be exempt from the performance standard if they meet the requirements for operating as a back-up or peaking capacity for the grid. This would require a unit to operate for no more than 450 hours/year, and emit no more than 150 kt of CO2 per year, roughly translating to 5% of the total hours of the year at 100% capacity (or a 5% capacity factor).

The inclusion of a "peaker provision" represents a reasonable and important flexibility for fossil gas units. Given the size and cost of the build out of non-emitting power required to meet even the average annual system needs, permitting a small amount of emitting generation that is highly deployable (can be turned on and off at short notice) can help provide reliability in an affordable manner while we work to transition our energy systems to 100% non-emitting sources and as deployable, non-emitting technologies and storage solutions become increasingly available and affordable.

This will be particularly important in provinces such as Alberta or Saskatchewan, which may face extended periods of cold temperatures where firm non-emitting generation is limited, and current non-emitting dispatchable generation, energy storage and demand management technologies are either unable or lack the necessary deployment to meet the balancing needs of the grid in the near term (in the medium term, non-emitting technologies should be expected to

[10] Canada Energy Regulator. *Canada's Energy Future 2023.* https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/canada-energy-futures-2023.pdf (2023).

greatly replace the role of peakers on these grids, but ensuring grid reliability during this transition will be essential).[11]

The capacity factor that is effectively permitted for peakers needs to be calibrated to ensure that necessary dispatchable power is available, but without allowing the peaker provision to become a loophole that permits more fossil gas use than is necessary. The current provisions risk being too restrictive. Under the currently proposed capacity factor of 5%, it may be uneconomic for units in deregulated energy-only markets like Alberta's to operate as peakers (because of insufficient revenue opportunity to cover fixed operating costs), and operators may simply choose to close instead of avail themselves of these provisions. While Alberta will in time need to consider market reforms that place an increased economic value on capacity services to help incentivize peakers to be available, the CER will also need to ensure that it is not unduly limiting the economic operation of facilities that system operators see as necessary for the near-term reliability of their grids.

While comprehensive data is limited in Canada regarding the historic capacity factors of peaker facilities, there are some reference points available in other jurisdictions. In the U.S., the average capacity factor for a peaker plant was around 11.75% between 2017 and 2021, with a California study estimating that gas peaker plants in the state averaged less than 15% capacity factors.[12] Based on this assessment of the available data, we recommend that a capacity factor of not more than 15% should instead be used.

In order to mitigate the risk of gas units simply being run to the maximum capacity factor permitted regardless of actual grid needs for peaker services, the government should rely on a reformed carbon price to incentivize use of peakers gas only when their value to the grid is highest.[13] As discussed in greater detail below, setting a threshold value of zero for the OBPS treatment of the sector or removing the electricity sector from the list of emissions-intensive and trade-exposed industries under the OBPS and instead applying full pricing would provide a strengthened carbon price signal. This signal would both incentivize sparing use of peakers as well as incentivize development and use of energy storage technologies and other sources of flexibility, which will increasingly compete with fossil gas in performing peaking services.[14]

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[11] Reports such as the Pembina Institutes "Zeroing In" have documented the role that technologies and policies like energy storage, energy efficiency and demand side management can play in reducing the role of peakers, including in the period before 2035.
[12] U.S. simple-cycle natural gas turbines operated at record highs in summer 2022. *U.S. Energy Information Administration.* https://www.eia.gov/todayinenergy/detail.php?id=55680 (2023).; California Peaker Power Plants: Energy Storage Replacement Opportunities. *Physicians, Scientists, and Engineers for Healthy Energy.* https://www.psehealthyenergy.org/wp-content/uploads/2020/05/California.pdf (2020).
[13] Oved. M & Bailey. A. Ontario gas plants were supposed to run only during peak periods. Instead they're running most of the time, polluting the air you breathe. *Toronto Star.* https://www.thestar.com/news/canada/ontario-gas-plants-were-supposed-to-run-only-during-peak-periods-instead-they-re-running/article_8ba52f13-bd5a-541a-b80e-9f497ff498be.html (2023).
[14] Porzio, J., Wolfson, D., Auffhammer, M. & Scown, C. Private and External Costs and Benefits of Replacing High-Emitting Peaker Plants with Batteries. *Environmental Science & Technology* ***57*** (12) 4992-5002.

Treatment of facilities commissioned post-2025

Recommendation: Immediately apply an interim performance standard to "new" units that tightens to the level of the full standard by 2035.

In order to limit the continued deployment of unabated fossil gas, the CER relies on a performance standard that takes effect in 2035 (at the earliest). This approach, in the view of the Department of Environment and Climate Change Canada, will deter construction of unabated gas, given the limited time frame in which they would operate.

However, the delayed imposition of the standard creates a risk that new unabated units will be commissioned that are "net-zero ready" but that only undertake the work of making them compliant with the performance standard when and if doing so is required by law. In the event that a federal future government rescinds the CER, this new unabated gas capacity will be locked in.

To reduce this risk, we propose that any facility commissioned after 2025 be subject to an immediate performance standard that gradually increases in stringency, culminating in the full application of the established performance standard in 2035. This interim standard will ensure that only gas plants equipped with meaningful mitigation technology (whether CCS, or bioenergy or hydrogen blending) come online between now and 2035, thereby avoiding the lock-in of new, fully unabated gas capacity. It will also help accelerate investments in abatement technologies and other forms of low-emission generation, driving down technology costs and speeding up learning rates for their successful deployment.

There are a number of options for implementing this interim standard.

The government could establish an initial performance standard on new units slightly below 420 tonnes of CO_2 per GWh — the standard facilities would already have to meet under the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. This standard would gradually tighten linearly between 2025 and 2035, at which time the full performance standard of 60 tonnes of CO_2 per GWh would take effect.

Alternatively, the government could model an initial performance standard on the existing carbon capture exception, where compliance is assessed relative to an average level of performance over a number of years. Compliance could be tested on a multi-year basis, with gradually tightening compliance requirements for the average performance, eventually reaching the full performance standard of 60 tonnes of CO_2 per GWh taking effect in 2035.

In either design, these interim standards could be replaced in favour of the full standard in 2035, or the existing provisions for carbon capture exceptions could be offered in that year, as a way of providing additional runway to early CCS deployment. Either way, the interaction of the interim performance standard and the post-2035 exceptions would need to be carefully considered.

Complementary policy changes for ensuring a coherent and cost-effective federal policy package for electricity

The following section highlights some of the changes and new policy initiatives that will serve as useful complements to the CER in achieving its policy objectives.

Reforming the Output-based Pricing System (OBPS)

Attempting to drive greenhouse gas emissions to net zero through the regulations alone could risk straining grid reliability and significantly increasing costs. Instead, the federal government should rely on carbon pricing as a complementary policy to cost-effectively drive down emissions on the road to 2035, as well as to limit emissions associated with the various flexibilities the CER contains. In other words, where the CER establishes a larger trajectory and regulates the vast majority of use cases, the carbon pricing can and should incentivize reserving use of gas-fired generation to when its value to the grid is very high, in order to avoid paying the escalating price.

However, in order to ensure the carbon price is properly complementing the CER by providing a strong incentive to reduce emissions, its application to the electricity sector requires reform.

Currently, under the federal carbon pricing system the electricity sector falls under the OBPS, with specific benchmarks on different types of generation that shield generators (and ratepayers) from being exposed to the full carbon price. Multiple climate policy and environmental economics experts have argued that the electricity sector does not meet the standard required to be treated as an emissions-intensive and trade-exposed sector under the OBPS.[15] Treating the sector as such weakens the price signal on emissions, undermining the incentive to limit the use of emitting generation like unabated fossil gas. And the federal government's specific approach of using fuel-specific benchmarks and not allowing renewable generators to receive credits (as is the approach taken in Alberta) further dilutes the policy's incentives to reduce emissions. These issues limit the effectiveness of the price signal by reducing both the price that emitting generation pays and the advantage realized by non- or

[15] Shaffer, B. & Dion, J. Building on Canada's electrical advantage. *Policy Options*. https://policyoptions.irpp.org/magazines/january-2022/building-on-canadas-electrical-advantage/ (2022).; Dion, J. Do OBAs make sense for the electricity sector?. *Canada's Ecofiscal Commission.* https://ecofiscal.ca/2018/05/09/do-obas-make-sense-for-electricity/ (2018).

lower-emitting generation.[16] This dilutes incentives for emissions reductions at the points of both electricity dispatch and facility construction.

Reforming the federal government's approach to electricity sector carbon pricing will be critical to complement the flexibilities envisioned in the Clean Electricity Regulations and drive down emissions in line with climate goals. Whether emissions under the CER emerge from its use of a non-zero standard, the allowance of facilities to continue operating unabated until they reach their end of project life or the exceptions created for peaker plants, emitting generation must face a strong carbon price that disincentives unabated gas operation and facility construction except where its value to the grid is highest.

There are a number of reforms possible to address this issue. The government could remove the electricity sector from the OBPS and apply the full price of carbon to electricity, or it could reform how the OBPS applies to the electricity sector, removing the benchmarks that shield emitting generation from paying the full cost.[17] There are pros and cons to each approach, but regardless of which is taken, a critical design feature will be that associated revenues remain in-province and get returned to ratepayers. This will support affordability and incentives for electrification, maintain a strong carbon price signal (since operators and utilities still pay the full price), and avoid significant inter-provincial transfers.

Regardless of the approach taken though, provincial systems would need to go through an equivalency review before this change could take effect, since provincial systems that have been granted equivalency already exist in all provinces with GHG-emitting grids. Where the provincial systems already apply a strong price incentive against emitting generation, such as Alberta's TIER system, the provincial systems should be allowed to continue as equivalent to the reformed federal approach to carbon pricing.

Currently, the government is required to conduct an interim review of the OBPS by 2026, which will inform the benchmark criteria for 2027-2030 and beyond 2030.[18] While the proposed changes may not be possible prior to this timeline, it is essential that the Government of Canada signal in advance its intention to reform the OBPS treatment of the electricity sector, making clear that its intention is to apply the full carbon price no later than 2030.

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[16] Shaffer, B. Canada's new large-emitter pricing system might defeat the carbon tax's own purpose. *Maclean's*. https://macleans.ca/opinion/canadas-new-large-emitter-pricing-system-defeats-the-carbon-taxs-own-purpose/ (2018).
[17] Taking an OBPS approach that allows renewable generators to receive credits, as Alberta has done, would provide strong incentives but is likely not a viable approach at the federal level because it would lead to large financial transfers to hydro-rich provinces from provinces with thermal systems.
[18] The federal carbon pollution pricing benchmark. *Environment and Climate Change Canada*. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/federal-carbon-pollution-pricing-benchmark.html (2023).

Procuring negative emissions

While strengthened carbon pricing and the CER can help efficiently drive down emissions, some amount of residual emissions is still likely to remain after 2035. In order to meet the federal government's 2035 net zero target, Canada needs to ensure that it offsets these residual emissions.

A complementary policy to address these residual emissions would help assemble a coherent policy package that can meet Canada's net zero electricity goal. As the Canadian Climate Institute has previously argued, in addition to reducing emissions, we will need technologies that remove carbon dioxide from the atmosphere.[19] While nature-based measures like reforestation can play a role, the risk of impermanence in their sequestered emissions means they are not a reliable source of negative emissions. The focus of the complementary policy needs to instead be on engineered processes that directly capture carbon dioxide and permanently store it deep underground, including direct-air capture paired with carbon capture and storage (DAC-CCS) and bioenergy carbon capture and storage (BECCS), in order to ensure the permanence of sequestered emissions and deliver true net zero.

The federal government has a critical role to play here. These technologies currently see significant costs and lack a sophisticated approach to incentivizing their deployment. By zeroing in on addressing the emissions remaining from electricity in 2035, the government has a specific and declining body of emissions it can focus on offsetting, which will help build capacity and experience in negative emissions – as well as develop a sector that can in time offer increasing quantities of negative emissions to other potential buyers.

Electricity should not be a sector that requires negative emissions for the long-term. We have almost all the solutions we need to get electricity emissions to zero — it's mostly a question of deploying the technology and modernizing our systems. However, this deployment and modernization will take time, and using the residual emissions from electricity as an initial source of demand for negative emissions can help ensure that the technology is available for other sectors in the future. The need to address electricity sector emissions will fall over time as the grid further decarbonizes, freeing up the negative emission capacity to address other sources. This approach can be a form of industrial policy, aimed at improving Canadian capacity and competitiveness in a sector that will play a significant role in the global effort to mitigate and eventually reverse the effects of climate change.

The cost of procuring negative emissions to offset the residual emissions in electricity should be taken on by the federal government. This would include the costs of procuring sufficient negative emissions to offset the sector's post-2035 emissions. It could also include direct equity

[19] Bataille, C. & Lee, C. The federal carbon pollution pricing benchmark. *Canadian Climate Institute.* https://climateinstitute.ca/going-negative/ (2021).

investments, tax credits (as the government has done via the Investment Tax Credits (ITCs) in budget 2023 for carbon capture and DAC), or other supports.

This approach ensures that these costs are carried by the federal government, not the ratepayer. This avoids the costs of procuring negative emissions landing on the provinces (and their ratepayers) that face the largest challenges in reaching net zero generation.

Supporting reliable non-emitting generation

With the CER driving a shift to non-emitting generation, the federal government can play a major role in securing non-emitting grid reliability by targeting its funding and programming resources towards an increased role for demand-side solutions that can act as effective sources of electricity supply by reducing or shifting load.

Fundamentally, a focus on demand-side solutions is about supporting innovation in the electricity sector, driving the deployment of technologies that can help support affordability for ratepayers while at the same time providing valuable services to the grid, either by reducing demand for grid-based power or shifting it away from periods of peak demand or when renewables generation is lowest. These technologies will play an important role in supporting greater grid flexibility, helping further decrease the reliance on fossil gas and serving as an essential part of a portfolio of technologies that ensures grid reliability. Overall, Canadian utilities and system operators have been slow adopters of many of these technologies, limiting their current application. In contrast, other jurisdictions have been greatly accelerating the deployment of these technologies, largely to ensure there are non-emitting ways to ensure the reliability of their grids.[20]

All of these technologies have important roles to play, but a greater focus on demand-side solutions is warranted for several reasons. First, these technologies can present unique deployment and installation challenges, and the federal government can help identify and implement best practices through programming as well as supporting greater information sharing between utilities. Second, the existing ITCs the federal government has established do not support these technologies, tilting the playing field away from their deployment. This creates a risk that cost-effective interventions remain untapped, potentially raising overall costs. And finally, these technologies are focused on household demand, so the affordability benefits they unlock will often benefit households more directly than alternative grid-focused interventions. During a time of heightened cost-of-living challenges for many households, opportunities to reduce costs should be prioritized.

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[20] The U.S. has been closely watching the developments in Australia, where DERs have played a major role in displacing fossil gas power generation. This was followed by a $50 million investment into National Grid to deploy DERs in the U.S., looking to support great grid reliability and flexibility. Certain utilities, such as this Vermont utility has gone a step further and advanced plans to purchase and integrate small, household batteries to offset the costs of new power lines.

By stepping in to support the deployment of these technologies, the federal government would help address an important gap in the Investment Tax Credits it has proposed. Offering programming and other supports around them would help correct the distortion created by its current ITCs, reducing provinces' system build-out needs and costs in a way that directly benefited households.